Decision **DRAFT DECISION OF ALJ PULSIFER (Mailed 12/28/2004)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060.	Rulemaking 02-01-011 (Filed January 9, 2002)

OPINION ADOPTING COST RESPONSIBILITY REQUIREMENTS FOR 2001-2003

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OPINION ADOPTING COST RESPONSIBILITY REQUIREMENTS FOR 2001-2003

I. Introduction

This decision adopts "cost responsibility" obligations for the years 2001-2003 applicable to Direct Access (DA) load pursuant to the provisions of Decision (D). 02-11-022. The term "cost responsibility" refers to designated costs that are properly assigned to DA customers in order to avoid the shifting of such costs to bundled customers. By avoiding cost shifting, bundled customers are to remain "indifferent" on a "total portfolio" basis with respect to customers that migrated from bundled to DA service after July 1, 2001.

The designated costs include a share of the State of California Department of Water Resources (DWR) revenue requirements associated with power procured pursuant to legislative directive in Assembly Bill (AB) 1 from the First Extraordinary Session (AB 1X) (See Stats. 2001, Ch. 4). Designated costs also incorporate a share of "above-market" utility-retained generation costs, as prescribed in D.02-11-022. DA customers within Southern California Edison company's (SCE) service territory are responsible for a "Historic Procurement Charge" as authorized by D.02-07-032 as modified by D.03-09-016. DA customers within Pacific Gas and Electric Company's (PG&E) service territory are responsible for the "Dedicated Rate Component" associated with "Energy Recovery Bonds" to refinance PG&E's bankruptcy "Regulatory Asset" as prescribed in D.04-11-015.[1]

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[1] DA/DL customers' obligations with respect to the Dedicated Rate Component (DRC) were not calculated by DWR/Navigant pursuant to this proceeding, and such

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Cost responsibility applicable to DA customers is separately determined for each of the service territories of California's three major investor-owned electric utilities (IOUs): SCE, PG&E, and San Diego Gas & Electric Company (SDG&E).

Cost responsibility obligations also apply to Customer Generation Departing Load (CGDL) and Municipal Departing Load (MDL), based on the particular classification of the customer load involved, in accordance with the provisions of D.03-04-030 (for CG DL) and D.03-07-028 (for MDL),[2] respectively. We address DL cost responsibility obligations in Sections III and IV below.

The IOUs implemented tariff amendments effective beginning in January 2003 to collect a DA cost responsibility surcharge (CRS) capped at 2.7 cents/kWh pursuant to D.02-11-022 and D.03-07-030. The 2.7 cents/kWh CRS, however, does not represent the total accrued DA cost responsibility obligation. To the extent the actual DA or DL cost responsibility obligations, on a cents/kWh basis, exceed the 2.7 cents/kWh currently being collected through IOU tariffs, the difference is accounted for as an undercollection as prescribed in D.02-11-022 and D.03-07-030. The undercollections will be tracked and paid down by DA/DL customers over future periods, and applied as a corresponding reduction in bundled customer bills in accordance with D.02-11-022 and D.03-07-030. Accordingly, the cost responsibility figures adopted in this decision require no

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determination is beyond the scope of this decision. The process whereby such obligations will be determined is outlined in D.04-11-015.

[2] In D.03-08-076, the Commission granted limited rehearing of D.03-07-028 and D.04-11-014 resolved issues in this limited rehearing as well as other related issues concerning MDL CRS. In D.04-12-059, the Commission modified and clarified certain provisions of D.04-11-014.

immediate change in existing tariffs applicable to DA or DL customers, and no recalculation of individual customer bills is necessary.

In D.02-11-022, the Commission adopted a CRS methodology, but deferred adopting the actual obligations pending finalization of pertinent inputs to the calculation. The determination of the DA CRS obligation must be integrated and coordinated with the overall DWR revenue requirements, consistent with the DWR cost allocations adopted for the three IOU service territories. Because DWR costs are the major driver for the cost responsibility calculations for DA/DL customers, DWR, through its consultant Navigant Consulting Inc. (Navigant), has borne responsibility for producing the CRS calculations using its financial model.

In this decision, we adopt DA cost responsibility obligations covering the periods: (1) from September 20, 2001 (initiating DA suspension) through December 31, 2002 and (2) the 12 months beginning January 1, 2003.

II. Procedural Background

The record supporting the cost responsibility figures adopted in this order consists of technical workshops, model runs produced by DWR/Navigant, and parties' written comments, in coordination with Application (A.) 00-11-038 *et al.* proceedings relating to the DWR revenue requirement. Comments were filed by PG&E, SDG&E, SCE, the Alliance For Retail Energy Markets (AReM), the California Large Energy Consumers Association (CLECA), the California Retailers Association (CRA), the Energy Producers and Users Coalition and Kimberly Clark Corporation (EPUC/KCC), and The Utility Reform Network (TURN). A Joint Administrative Law Judge (ALJ) ruling, issued on December 10, 2002, in this proceeding and A.00-11-038 *et al.*, initiated the process to determine the calculation of applicable DA cost responsibility obligations. The ALJ ruling indicated that a workshop would be scheduled to determine the total DA cost responsibility obligation for 2003 once the Commission issued a decision adopting DWR revenue requirements for 2003.

On May 13, 2003, an ALJ ruling[3] provided parties with opportunity to comment on Navigant's preliminary calculations and explanations related to undercollections for 2001-2002 attributable to DA customers. A conference call was scheduled for May 14, 2003 for interested parties to discuss the DWR document. Parties filed comments on May 19, 2003.

An ALJ ruling dated June 24, 2003, solicited comments concerning coordination issues with proceedings in A.00-11-038 et al. in determining the total cost responsibility obligation of DA and departing load to finalize the DWR revenue requirements for 2001-02 and 2003. A subsequent ruling dated August 4, 2003 provided a further opportunity to comment with respect to what, if any, additional data submissions and/or proceedings were necessary to complete the record. Parties filed responsive comments on August 22, 2003.

DWR conferred with the IOUs to obtain supporting cost data for the 2001-02 period required for computing the "total portfolio" indifference costs in accordance with D.02-11-022. The IOUs provided DWR with relevant utility retained generation (URG) costs to be incorporated into the calculations.

By ruling dated November 14, 2003, a schedule was set to determine the total cost responsibility obligations of DA and DL customers applicable to

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[3] The May 13, 2003 ruling provided a substitute document to replace the one that had been provided by prior ruling issued on May 12, 2003.

2001-02 and also for 2003 within this proceeding.[4] SCE, PG&E and SDG&E were directed to serve on parties of record by December 8, 2003, the supplemental recorded data, as noted above to the extent necessary to compute 2001-02 "total portfolio" costs. Parties were given the opportunity to offer alternative calculations.

DWR issued a model run on December 14, 2003, together with a report describing its calculations. A workshop was convened on December 16, 2003, for parties to question DWR concerning its modeling. The Commission's Energy Division issued a Workshop Report on December 21, 2003. Parties filed comments on DWR's modeling runs and the Workshop Report on January 16, 2004, and reply comments on January 30, 2004.

DWR sought additional Commission direction on certain issues before presenting final calculations. An ALJ ruling, issued on May 5, 2004, provided further guidance concerning the calculation of DA/DL CRS obligations for 2001-02 and 2003.[5] DWR/Navigant produced a subsequent run of the CRS calculations, served on parties on June 18, 2004. A teleconference call was scheduled for parties to ask questions and comment.

On August 17, 2004, the Commission's Energy Division released Navigant's further revisions to the spreadsheets and supporting data underlying

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[4] An ALJ ruling in Application (A.) 00-11-038 *et al.*; dated November 4, 2003, granted certain parties' motion to strike relating to testimony relating to Direct Access issues since those Direct Access issues are being addressed within the scope of this proceeding.

[5] By ALJ Ruling dated May 21, 2004, the due date for the modeling runs was revised to June 18, 2004. Investor-owned utility inputs were to be provided by June 8, 2004.

the DWR CRS model changes. Comments regarding the August 17, 2004, CRS calculations were filed on August 30, 2004.

III. Treatment of DL Volumes in the DA CRS Calculation

Cost responsibility applies not only to DA customers but also to certain CGDL and MDL, as prescribed by Commission decision. The applicability of DWR charges depends upon the relevant classification of the customer group involved, with reference to the governing provisions adopted in D.03-04-030 (for different categories of CGDL) and D.03-07-028, as amended on rehearing, addressing CRS applicability to categories of MDL. Since both DA and DL customer groups are to bear their "fair share" of cost responsibility, as determined by Commission order, applicable DA and DL load must be identified and utilized in the modeling runs.

In calculating the CRS, however, parties questioned whether non-exempt DL volumes should be lumped together with DA load into a single indifference calculation. AReM argues that combining these two load volumes may distort DA customers' cost responsibility in future years and may unnecessarily prolong their CRS payments because most DL volumes will occur in the future, when DA customers will be closer to paying off their CRS obligations.

A possible solution is to create a separate DL-in / DL-out indifference calculation, applicable only to DL costumers. Doing so would also make it easier to incorporate any New World URG stranded costs left behind by DL customers for which DA customers bear no responsibility.

Since the level of eligible DL volumes currently responsible for paying the CRS is small, the inclusion of DL volumes does not significantly affect the current total bundled customer indifference calculation. However, certain parties believe that future DL volumes could be substantial, in which case it would be necessary to include DL volumes <u>and related costs</u> that DL customers leave stranded in the CRS calculation. Including only the DA volumes would lower the overall level of the CRS while not making bundled customers indifferent to the stranded costs left behind by the DL customer.

PG&E, as well as DWR and TURN, recommend that both departing load as well as direct access load be reflected in the "DA-in" / "DA-out" calculations. In calculating the indifference amount, these parties recommend that departing load must also be included in the DA-in run, in order to hold bundled customers indifferent to the exodus of this load from bundled service, as well.

PG&E also agrees that the direct access and departing load obligations should be tracked separately, and proposed the establishment of the Departing Load Shortfall Account (DLSA), to complement the already adopted Direct Access Shortfall Account (DASA).

As previously indicated, for purposes of determining CRS applicability, there are two broad categories of departing load: (1) customer generation and (2) municipal. With respect to customer generation, the Commission in D.03-04-030, provided an exception from the DWR power charge for "grandfathered" DL, defined as DL that becomes operational on or before January 1, 2003. With respect to the DWR Bond Charge, D.03-04-030 assigned CGDL cost responsibility, as implemented by Commission Resolution E-3831. The decision was issued on April 8, 2003. Accordingly, there are no DWR power or bond-related costs included in Navigant calculations of CRS for customer generation DL for 2001-2002.

As the basis for determining CRS obligations attributable to MDL customers, the Commission has issued a series of decisions in this proceeding, most recently, D.04-12-059, in which we resolved applications for rehearing of D.04-11-014. This series of decisions set forth the principles and criteria whereby

CRS is applicable to MDL customers. Since the most recent MDL decisions were issued after the most recent CRS modeling runs had been completed, the effects of these decisions are not incorporated into the modeling results for DL summarized in this decision. Moreover, we directed in D.03-07-028 that a further MDL billing and collection implementation phase must be conducted to determine the applicable MDL customers and usage for computing CRS obligations. Thus, pending further developments in the MDL billing and collection phase, we defer final determination of the CRS obligations applicable to MDL.

Of the three IOUs, only PG&E included DL volumes in the data it provided to Navigant associated with the CRS power charge obligation for 2003 in its service territory. SCE and SDG&E included zero DL volumes associated with the CRS power charge obligation for 2003 in their respective service territories. Although PG&E's calculation reflects some DL volumes, they are quite de minimis. As a percentage of total volumes eligible for CRS obligations in the PG&E service territory, the DL volumes constitute the following de minimis percentages:

	DL as a % of Total Eligible CRS Power Charge Volumes
2001	0.0657%
2002	0.0687%
2003	0.0707%

DWR has included the de minimis volumes of DL in its CRS calculations, without specifically distinguishing separate discrete categories of customer generation or municipal DL. Given the immaterial impact of DL volumes on the overall calculation at least for 2001-2003, we conclude that it is not necessary to make revisions to the DWR model at this time to separately calculate a CRS for such DL volumes apart from the overall CRS calculation. We recognize, however, that eligible DL volumes, both for customer generation and municipal load could grow in future years. With such growth, potential disparity in CRS allocation could occur in future periods from combining DA/DL volumes together in a single calculation, as addressed above. This disparity may result from different rates of growth in DA versus DL volumes. Likewise, any differences that may be subsequently adopted in the surcharge caps applicable to CRS for DA versus MDL may also warrant separation of the indifference calculation for each load category. We thus agree that separate calculations will be necessary for future periods whereby Customer Generation and MDL volumes are segregated from DA volumes for separate indifference calculations.

IV. Cost Responsibility Obligations for DWR Bond Charge

Among the Cost Responsibility Elements is the DWR Bond Charge. The DWR Bonds were issued in the fall of 2002 to pay back money borrowed from the State of California General Fund since January 17, 2001, and to pay off interim loans for the same period, and to fund DWR's operating and reserve accounts at the required minimum levels. As previously adopted by the Commission in D.02-11-074,[6] the DWR Bond Charge recovers debt service paid by DWR to bond holders over a 20-year period. The Bond Charge is an equal cents per kwh charge applied across certain bundled, DA and DL customer groups. The Table in Appendix C summarizes the DWR Bond Charge undercollections as computed by DWR/Navigant in its August 17, 2004 submittal. The Bond Charge became applicable to bundled and DA nonexempt

[6] Attachment A of D.02-11-074 replaced the entire text of D.02-10-063.

load on November 15, 2002, at which time bundled customers began paying the charge. The Bond Charge did not become effective for or applicable to Customer Generation DL until April 3, 2003. DA customers did not begin paying the DWR Bond Charge until September 2003. CG customers began paying the DWR Bond Charge as of July 19, 2004 in SCE and SDG&E territories and September 1, 2004 in PG&E territory. Municipal DL customers have not yet begun paying the DWR Bond Charge.

The DWR Bond Charge undercollections calculated by Navigant are set forth in Appendix C between DA and DL customers on an aggregate basis by utilizing the relative percentage share of DA and DL demand volumes by IOU and by year, as depicted in the Navigant calculations, as summarized below:

Departing Load Responsible for DWR Bond Charge
As a Percentage of Total Eligible Volumes

	PG&E	SCE	SDG&E
2001	0%	0%	0%
2002	1.30%	0.43%	2.01%
2003	7.38%	6.19%	11.95%

The Navigant model does not separately distinguish DL volumes as between Customer Generation or Municipal load, nor subcategories within these two major DL categories. Moreover, as noted previously, with respect to MDL, the applicable volumes for DWR Bond Charge billing purposes is yet to be quantified through the billing and collection phase of this proceeding. Without accurate volumetric demand data, we cannot compute the precise allocation of DWR Bond Charge undercollections applicable to MDL. Moreover, parties have not previously had the opportunity to review Navigant's calculations of DWR Bond Charge undercollections through 2003. Accordingly, we shall defer adopting the calculated results as final figures at this time. We intend to adopt final figures for DWR Bond Charge undercollections applicable both to DA and DL customers in conjunction with our subsequent order regarding the true up of 2003 DA CRS power charges.

V. Cost Responsibility for Power Charges

A. Framework for Calculations

Based upon the methodology adopted in D.02-11-022, DA load is held responsible for designated power charges computed on a "total portfolio" basis. Accordingly, in order to determine the applicable DA cost responsibility, it is first necessary to determine the overall revenue requirement for DWR and URG costs. DWR revenue requirements for the 2001-03 periods have been adopted through proceedings in A.00-11-038 et al., as discussed below. We separately address pertinent issues relating to URG and CTC in Section VI below.

The DA cost responsibility calculation solves for the incremental cost to be charged to designated DA customers required to make bundled customers indifferent with respect to the cost effects of DA migrations. In particular, the intent of the calculation is to prevent DA customers from escaping from their responsibility to bear a fair share of the costs incurred by DWR to deal with California's energy crisis pursuant to AB 1X.

As prescribed by D.02-11-022, the computation requires comparing costs: (1) assuming bundled load includes DA load that migrated after July 1, 2001 (i.e., the "DA-in" scenario), and (2) assuming bundled load excludes such migrated DA load (i.e., the "DA-out" scenario). The incremental costs resulting from the DA-in versus DA-out forms the basis for assessing cost responsibility for DA and DL.

Each scenario is calculated through modeling of the dispatch of available generation resources, incorporating assumptions for load growth, natural gas price, and generation availability (among others). DA cost responsibility for power charges incorporates elements for DWR power contracts, spot purchases, surplus sales, ISO charges, and administrative and general costs as contained in DWR's revenue requirement.

B. Reliability of Modeling Results

CMTA argues that the DWR modeling results are based on opaque assumptions that cannot be verified by outside parties. Although the actual numerical inputs used have been disclosed, CMTA complains that the basis for the numbers is not verifiable. The modeling results for 2001-2002 use utility-supplied data for the costs and MWh volumes of URG, apparently including power purchases and sales to serve the net-short gap between total utility load and total utility generation and DWR contracts. The utilities represent that the data inputs to the model are historically accurate. CMTA argues, however, that DA/DL customers that actually pay the CRS charge are unable to verify the data. CMTA argues that in order to be more transparent, the utility-supplied data should be separated at least into distinct categories for URG resources and net market purchases (*i.e.*, purchases less sales), with actual cost and volume data for each component.

CMTA argues that no credible basis exists for claiming that such information is too sensitive to share with DA/DL customers that must ultimately pay the CRS. At a minimum, CMTA believes this information should be reviewed by CPUC staff or some other independent party to verify the model inputs. CMTA observes that since it is the blended cost of DWR and URG resources that determine average cost in the "DA-Out" case, the model results are quite sensitive to variations in these costs. It is the difference between the bundled DA-Out price and the price assumed for the DA-In/Out increment that in large part determines the magnitude of the CRS balance.

In particular, SDG&E withheld certain market-related data from disclosure to parties relating to 2003 transactions. On August 10, 2004, an ALJ ruling was issued directing SDG&E to provide a justification concerning its claims that certain utility data for 2003 was confidential and should not be disclosed to other parties in the proceeding. SDG&E provided a response to the ALJ ruling on August 17, 2004. In its response, SDG&E provided parties with the data underlying the 2003 CRS undercollection and accrual calculations that SDG&E believed could be shared with the public. SDG&E also provided an explanation concerning the remaining data that it continued to consider confidential as to why SDG&E believed that disclosure of such data would be detrimental to SDG&E and to its bundled customers.

The only party filing a response to SDG&E on this issue was EPUC *et al.* on August 31, 2004. Based on review of the data released by SDG&E, EPUC *et al.* determined that the only Customer Generation DL CRS obligation in SDG&E's territory for 2003 is for the DWR Bond Charge. EPUC *et al.* understands that the amount of DL shown as responsible for the DWR bond charge does not include any excepted load served by Customer Generation. That obligation only began to take effect for Customer Generation on April 3, 2003. Given this understanding, EPUC *et al.* take no position regarding the need for additional information underlying the 2003 CRS calculations for SDG&E.

Accordingly, we find no necessity in this particular instance to require disclosure of the data that SDG&E considers to be confidential and proprietary. DWR has indicated that it is bound by nondisclosure agreements and cannot unilaterally release confidential information. Nonetheless, DWR has responded to data requests and answered questions of parties concerning its calculations through successive rounds of comments and workshops. Although various parties have expressed some degree of frustration with the process of reviewing the CRS modeling calculations, no party has formally filed a motion to compel production of confidential information. Accordingly, we find insufficient basis to delay further the final adoption of CRS calculations because of generalized statements that some supporting data was kept confidential.

Nonetheless, we do not prejudge how future disputes may be resolved concerning parties' access to data alleged to be confidential as we continue to balance the public interest in an open and public proceeding with parties' claims of harm from disclosure of data alleged to be proprietary or commercially sensitive. To the extent that a party believes that specific information required to validate CRS calculations is being withheld without proper warrant, the party should promptly bring the matter before the Commission through a motion to compel after pursuing reasonable efforts to access the data including through the use of a nondisclosure agreement.

C. Cost Responsibility for Power Charges for 2001-2002

We hereby adopt Cost Responsibility Power Charges for 2001-2002, set forth below, as computed by Navigant, applying the DA-in/out total portfolio indifference cost methodology adopted in D.02-11-022. The calculations incorporate the applicable share of DWR costs assigned to each IOU service territory consistent with D.02-02-052 and with the 2001-02 DWR true-up in

D.04-01-028 (in A.00-11-038 et al.).[7] DWR's financial model had initially assumed a 3% DA level for July 2001 using SCE-supplied data. SCE checked this figure by examining its billing data for customers who were DA on that date, and determined that the correct level of DA load as of July 2001 was actually only 0.9%. DWR reran its financial model with the correct DA percentage for SCE.

We adopt Navigant's June 18, 2004 calculation of the cost responsibility obligation for power charges covering 2001-2002 in the amounts for each IOU service territory as summarized below:

Undercollected Power Charge Balance at Year End ($000s)

	PG&E	SCE	SDG&E
2001	$ 36,991	$ 53,883	$ 1,841
2002	$234,870	$354,751	$42,696

The level of the CRS undercollection in the SDG&E service territory is significantly lower than that of the other two IOUs because of the effects of the relative differences in DA volumes that generate CRS obligations versus the DA volumes responsible for paying the CRS. In D.02-11-022, the Commission established July 1, 2001, as the starting date to be used for measuring incremental DA volumes that generate CRS obligations under the DA-in/DA-out methodology. On the other hand, loads that migrated from bundled service to DA access after February 1, 2001 are responsible for paying the CRS. In the case of SDG&E, the DA load that pays the CRS obligation is more than four times the size of the load that generated the charge. The other two IOUs do not exhibit

[7] The 2001-2002 true-up calculation of DWR Power Charges incorporated in D.04-01-028 is set forth in Appendix B of this decision.

such a large spread between these two DA load figures. As a result, the SDG&E CRS obligation is significantly lower than the other two IOUs. The effects of these figures for 2003 and 2004 are summarized below:

	DA % that generates CRS Obligation	DA% that Pays CRS Obligation
PG&E	9.40%	10.33%
SCE	11.0%	13.49%
SDG&E	2.8%	13. 45%

Since DA load cost responsibility obligations began to accrue after September 20, 2001, the balances for 2001 reflect only the period from September 21 through December 31, 2001. The balances for the year 2002 reflect a full 12 months period. Because the IOUs did not begin billing DA load for a DA CRS until January 1, 2003, however, undercollections accrued during 2001 and 2002. Bundled customers funded the shortfall attributable to the DA undercollection but will be reimbursed in future periods, as prescribed in D.02-11-022. Supporting calculations showing accruals and collections for 2001 and 2002 are set forth in Appendix A of this decision.

The CRS undercollections that accrue subsequent to January 1, 2003 are more controversial because of disagreements concerning how to incorporate "New World" URG into the indifference calculation. We address the effects of "New World" URG on the 2003 CRS undercollections in Section VII.C below.

Subsequent its June 18, 2001 submittal, DWR provided further revised calculations to the Commission's Energy Division. On August 17, 2004, the Commission's Energy Division released to parties DWR's revised set of CRS calculations for 2001-2002.[8] The ending CRS balances for each IOU service territory as calculated by DWR in the August 17, 2004 transmittal are as follows:

CRS Power Charge/CTC Ending Balances ($000)			
	PG&E	SCE	SDG&E
2001	39,622	57,475	-
2002	246,210	403,415	8,070

CRS Bond Charge Ending Balances ($000)			
	PG&E	SCE	SDG&E
2001	-	-	-
2002	4,073	5,736	685

The ending balances for the DWR Power Charge/CTC component of the CRS shown in the August 17, 2004 transmittal vary from the figures distributed by DWR on June 18, 2004 for the reasons discussed below.

In its June 18, 2004 submittal, DWR calculated bundled sales as the sum of DWR contracts, URG, spot purchases, and surplus sales. After conferring with the IOUs in late June 2004, however, DWR determined that bundled sales vary somewhat with this calculated figure, primarily due to California Independent System Operator (ISO) energy not captured in these categories. In its August 17, 2004 calculations, therefore, DWR revised its bundled sales figures provided by the IOUs. The difference between the June 18 and August 17, 2004 versions are as follows:

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[8] The calculations are derived contained in the Excel model attached to DWR's submittal, identified as CFMGV04-8-17-04 CRS filing-two-year (1) zip.

Bundled Sales 9/2001-12/2002 (GWh)			
	PG&E	SCE	SDG&E
June 18 Model	95,312	88,163	18,640
August 17 Model	95,308	89,483	19,251

In its June 18, 2004 calculations, DWR calculated its 2001-2002 revenue requirement using the Commission approved DWR accrual charge times an allocated amount of DWR energy, based on D.02-02-052. In its revised August 2004 calculations, however, DWR recast the revenue requirement to reflect the amount of revenue that DWR actually received from bundled customers in 2001-2002. In the revised approach, the CRS reflects the amount actually paid by bundled customers as opposed to the amount that should have been paid. While acknowledging that the Commission's adopted approach is reasonable, DWR argues that its August 17, 2004 revised approach is more equitable and straightforward in representing the indifference amount.

In revising the September 20, 2001 through December 31, 2002 revenue requirement calculation, DWR also apportioned a $444 million remittance made by PG&E relating to Western Area Power Authority (WAPA) transactions. Although PG&E did not make the WAPA payments in the 2001-2002 period, $444 million of PG&E's lump sum payment to DWR in 2003 was attributed to 2001-2002 on a pro rata monthly basis in DWR's revised calculations.[9] CMTA objects to DWR's August 17th revisions, arguing that the use of actual DWR remittance amounts is less accurate than the Commission-approved DWR rate adopted in D.02-02-052 times an allocated amount of DWR energy.

[9] D.04-01-028.

CLECA likewise argues that DWR/Navigant changes to the modeling was done in a manner inconsistent with Commission decisions, and questions the accuracy, consistency, and reliability of the DWR results. CLECA argues that such alterations so late after the actual event have frustrated DA customers, and added to concerns about the accuracy of the results. CLECA expresses concern both on the continuing revisions of numbers, and on the burden imposed by the instability of the entire process of determining the DA CRS obligation.

Based on its review of DWR's latest computations, PG&E believes that the 2001-02 CRS obligation amount can be brought to closure. DWR based its DA/DL cost responsibility calculations for a particular time period based on the amounts actually remitted to DWR for that time period. PG&E does not object to this approach as long as it is used not just for 2001-2002, but also for 2003, and subsequent years on a consistent basis as well, so long as the DA/DL cost responsibility calculation is made.

Due to the unique nature of the WAPA remittance and the way it was handled in the calculation of the true-up of the 2001-2002 DWR power charges, PG&E does not object to reclassifying the 2003 WAPA remittance as though it were made in 2001-2002 for purposes of calculating the DA/DL cost responsibility.

We conclude that DWR's model run of June 18, 2004 represents the most appropriate basis for determining the 2001-2002 cost responsibility, and we shall adopt it. These calculations are properly based on the methodology that was prescribed by the Commission, utilizing the adopted DWR power charge and allocation by IOU service territory. By contrast, DWR's subsequent August 17, 2004 revision deviates from the directives that were provided to DWR for making the calculations. As noted by CMTA, tracking the amounts actually paid by bundled customers will produce over- or undercollections in DWR costs. For example, for 2003 DWR reduced its revenue requirement by approximately $1 billion.[10] Given that the point of the DA CRS includes mitigation of the high cost of DWR contracts, it would only exaggerate these costs to use an inflated remittance charge.

DWR's assignment of 2001-2002 WAPA costs incurred in 2003 to the 2001-2002 period is contrary to the actual remittance cost approach taken for the DWR contracts. The balance of cost responsibility attributed to 2001-2002 should reflect the revenue requirement in effect during that period. Since the WAPA costs were actually paid in 2003, those costs are properly included as part of the year 2003 cost responsibility calculation. Accordingly, we shall not adopt DWR's August 2004 revised calculations reassigning WAPA costs that were actually remitted in 2003.

D. Cost Responsibility Obligations for 2003

We likewise adopt the applicable Cost Responsibility Power Charge obligations for calendar year 2003, derived using the DWR revenue requirement for 2003, as implemented by Commission decisions. D.02-12-045 implemented a DWR revenue requirement for 2003 on an interim basis,[11] and adopted an allocation among the three IOU service territories. D.03-09-018 implemented a supplemental determination of 2003 DWR revenue requirements, incorporating a reduction of $1.002 billion, and directed that bundled utility customers receive a one-time bill credit for the reduction. The Commission further stated that issues

[10] See D.03-07-030 at p. 39.

[11] D.02-12-045 was corrected by D.02-12-052 and amended by D.03-02-031.

relating to impacts of the 2003 DWR revenue reduction on DA/DL customers were to be addressed in the instant proceeding.

Navigant thus computed 2003 DA/DL cost responsibility obligations consistent with the DWR revenue requirements and allocations as implemented in D.02-12-045 and D.03-09-018. Although the IOUs began to bill and collect a 2.7 cents/kWh CRS beginning in 2003, the CRS did not fully recover the ongoing cost responsibility obligation. Accordingly, Navigant computed the amount of undercollection to the extent that actual obligations exceeded the revenues collected under the capped CRS. We hereby adopt Navigant's June 18, 2004 calculations of cost responsibility covering the 2003 calendar year (corrected for certain computional errors),[12] resulting in December 31, 2003 undercollections, as summarized below:

Undercollected Power Charge Balance at Year End ($000s)

PG&E	SCE	SDG&E
$251,747	$540,837	$40,818

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[12] The following computational errors in the figures set forth in the Draft Decision have been corrected in the adopted figures in Appendix A Table 1. In comments on the Draft Decision, SCE identified a computational error in the CRS balance for the SCE service territory as of year end 2003. The corrected total for year end 2003 for SCE is $521,895 before accrued interest is applied. DWR also noted that the 2003 CRS ending balances set forth in the Draft Decision inadvertently excluded one-half of the accrual for the year 2003. We have corrected these computational errors and reflected the corrected totals, with accrued interest in Appendix A, Table 1. SCE also identifies a computational error in the ending 2003 balance in Appendix D of the Draft Decision. We have accordingly corrected Appendix D to show a balance of $316,142 plus interest of $34,711.

We consider below the contested issues raised by parties in reviewing DWR's calculations covering the year 2003, as discussed in the pertinent sections below.

VI. Utility Retained Generation (URG) and Competition Transition Charges (CTC) Issues

A. Framework for Analysis

Under the total portfolio method adopted in D.02-11-022, both DWR and URG sources of power are recognized in computing DA cost responsibility for a power charge. For DA load responsible for paying a DWR power charge, DWR computes a blended charge that incorporates the combined effects of DWR and URG sources of power. As adopted in D.02-11-022, the CRS incorporates "above-market" URG costs in excess of a designated market benchmark (set at 4.3 cents/kWh for the year 2003). The "above-market" URG costs were intended to capture DA customers' cost responsibility on a total portfolio basis.

Within the blended charge, a provision may be derived residually representing costs mandated for recovery under AB 1890, commonly referred to as the "competition transition charge" (CTC). The specific level of the CTC, however, does not need to be separately calculated for customers who pay both the CTC and the DWR Power Charge, since the indifference calculation produces a total charge that is merely divided into somewhat arbitrary CTC and Power Charge components. If the CTC component is higher, the Power Charge will be lower by an offsetting amount, and vice-versa.

For that portion of DA load that is not required to pay a DWR power charge, however, a separate charge applies that reflects only the CTC.[13] The separate CTC amount really matters, therefore, only for those customers who pay only the CTC and not the DWR Power Charge. The load of customers paying only CTC is not reflected in the DWR/Navigant model.

AReM argues that there is no longer any ongoing CTC, adopted as a part of AB 1890. AReM cites Commission decisions addressing the issue of transition cost recovery during the AB 1890 transition period. In those decisions, however, the Commission did not address the recovery of ongoing transition costs, the recovery of which, by definition, is not limited to the AB 1890 transition period. Public Utilities Code Section 367(a)(1), for example, provides employee related transition costs may be collected, subject to certain conditions, through 2006, while Section 376(a)(2) provides that recovery of the CTC associated with ongoing power purchase obligations shall continue for the life of the contracts. Nothing in the decisions cited by AReM changes these provisions of the Public Utilities Code, which remain in full force. Accordingly, a CTC provision still needs to be collected from DA customers to the extent authorized in this decision.

Modesto Irrigation District argues that MDL customers served by publicly owned utilities (such as Modesto) cannot be assessed CTCs using the methodologies established for DA and self-generation DL customers, and that no CTCs can be imposed on any departing load served by a publicly-owned utility

[13] In D.02-11-022, that portion of DA load that had been continuously on DA status prior to February 1, 2001 was not required to pay a DWR power charge.

except as authorized by AB 1890. Modesto argues that since PG&E's authorization to collect CTC from departing load customers under its tariff "E-Depart" expired on or before March 31, 2002, PG&E should not be granted a retroactive CTC rate through this proceeding.

D.02-11-022 adopted a 4.3 cents/kWh market proxy to be applied in calculations of CTC through 2003. D.02-11-022 also specified that the proxy value shall be updated annually thereafter. In D.03-07-030, we stated that any CTC component applicable to the DA customers covering the 2001-02 period and 2003 period would be adopted through this rulemaking proceeding. For 2004 and thereafter, CTC values are to be determined in the annual Energy Resource Recovery Account (ERRA) proceeding for each utility.

Because ongoing CTC for customers not subject to the DWR Power Charge will be determined in each utility's ERRA proceeding and not in this docket, AReM's argument that there is no longer any basis for an ongoing CTC charge is moot with respect to customers subject to an indifference-based CRS.

As noted at the December 16, 2003 Workshop, DWR's financial model does not include CTC applicable to those customers who only pay the CTC (i.e., those who do not pay the DWR Bond or DWR Power Charge). Thus, undercollection figures produced by DWR do not reflect the cost responsibility of those customers that only pay the CTC. Thus, each IOU remains responsible for calculating the obligation that applies for those DA/DL customers that pay only a CTC, but not a DWR power charge.

CMTA argues that CRS calculations should reflect the most recent determination by the Commission based on a substantial review of URG costs. CMTA proposes use of URG revenue requirements found in D.02-04-016 (which adopted interim URG revenue requirements for 2002) to calculate CTC for

2001-02 and 2003. CMTA opposed PG&E's CTC revenue requirement proposal that was based on PG&E Advice Letter 2233-E that significantly updated the URG levels adopted in D.02-04-016. For past periods, CMTA believes that recorded URG costs and volumes should be used to estimate CTC. CMTA claimed PG&E's CTC calculations are not sufficiently "transparent" nor consistent with the other utilities.

We conclude that the URG costs that have been submitted by the IOUs for purposes of computing the cost responsibility indifference amount for 2001-2002 and for 2003 are reasonable for use in deriving the calculations as produced by Navigant, with the exception of data relating to "New World" URG, as discussed separately in Section VI.C below. Parties were provided an opportunity to review the URG data and to conduct discovery pursuant to it. In the sections below, we discuss the URG data submitted by the IOUs for purposes of finalizing the Cost Responsibility Power Charge calculations.

For the undercollection calculations to be accurate, CMTA argues that they should reflect a realistic price for acquiring power to serve the DA/DL loads in the DA-In case. CMTA questions, however whether the 4.3 cents/kWh CTC proxy accurately reflects market prices for energy and capacity. CMTA argues that the indifference calculation is extremely sensitive to a $10 per MWh variance in the assumed cost of procuring power for the DA/DL load increment.

We have already adjudicated and adopted the 4.3 cents/kWh proxy applicable to 2003. It is beyond the scope of this proceeding to relitigate the methodology for calculating the CTC proxy for 2003 since it has already been decided in D.02-11-022. We agree, however, that the adopted 4.3 cents/kWh market price benchmark needs to be trued up to reflect actual natural gas prices as part of the overall true up of 2003 CRS requirements. As noted by CMTA in its comments on the Draft Decision, the 4.3 cents proxy price adopted in D.02-11-022 incorporates a gas price assumption of $3.88 per MMBtu although actual burnertip gas prices in California for 2003 were approximately $5.40 per MMBTU. In view of the disparity between the original forecast and actual natural gas prices for 2003, a true up of the 4.3 cents/kWh proxy to incorporate actual gas prices is necessary in order to reflect the accurate amount of CRS undercollections. In recognition of the need for updating of the proxy, moreover, we provided for annual updating of the proxy as part of each IOU's ERRA proceeding. The 4.3 cents/kWh benchmark was largely based on gas price forecasts for 2003. We recognize that gas prices have changed considerably since the benchmark was adopted. The updating of the 4.3 cents/kWh proxy for 2004 and thereafter should be taken up within the respective ERRA proceedings.

B. URG and CTC Disposition Pertinent to Each Investor-Owned Utility

1. PG&E

PG&E submitted data on December 8, 2003 consisting of recorded URG expenses for 2001-2002 (including employee-related transition costs); (2) first-quarter of 2003 recorded CTC-eligible URG costs and demand volumes, together with forecasts of the remaining three quarters of 2003, as well as for 2004. PG&E also provided bundled and DA and DL load data for the applicable periods of 2001-2003. PG&E also provided 2003 and 2004 Ongoing CTC amounts.[14] The data submitted by PG&E was utilized by DWR/Navigant in

[14] PG&E concurrently filed a motion for authority to file and maintain confidential, commercially sensitive, proprietary information under seal. No party filed a response in opposition to PG&E's motion. It is accordingly granted.

computing the CRS obligations applicable to the PG&E service territory. We find the URG data submitted by PG&E to be reasonable as a basis for computing the applicable CRS obligations for the 2001-2003 periods, and accordingly adopt it.

PG&E believes that no CTC estimate needs to be adopted for billing its customers covering the 2001-2002 period, and that no tracking of this item is necessary for PG&E. PG&E provided no separate CTC calculation applicable to the 2001-02 DA CRS undercollection period.

PG&E previously collected CTC revenues from DA customers during 2001-2002 through the one-cent electric procurement surcharge (EPS) implemented in D.01-01-018. The EPS was imposed on an interim basis to assist in paying for power during the energy crisis in 2000-2001. AReM argued that direct access customers should not have paid the one-cent per kWh EPS that was instituted by the Commission in D.01-01-018, and requested that EPS revenues paid by PG&E's DA customers be credited back in order to lower the 2001-2002 CRS undercollection.

DA customers' obligation relating to the one-cent EPS was resolved in D.04-02-062 in which the Commission adopted a Rate Design Settlement implementing provisions of D.03-12-035 in PG&E's bankruptcy proceeding. As prescribed in D.04-02-062, past contributions by DA customers during 2001 and 2002 through payment of the one-cent EPS and residual CTC were deemed to be the full and final obligation of these customers with respect to PG&E's headroom. These amounts were not to be altered, reclassified, or reconsidered in any subsequent proceeding. Accordingly, in view of the disposition reached in D.04-02-062, nothing further needs to be decided in this decision concerning CTC issues for PG&E with respect to the 2001-2002 period.

Likewise, PG&E argues that there is no need to determine a separate ongoing CTC element for the 2003 period. As noted above, the indifference calculation does not require separate calculation of CTC. Moreover, PG&E does not propose to recalculate DA or DL customers' bills for this time period, regardless of the combination of responsibility that the customer has for the DWR bond charge, ongoing CTC, or the DWR power charge.

We agree that there appears to be no necessity to determine a separate ongoing CTC for PG&E for 2003, based on the factors noted above. Accordingly, we shall not adopt any separate ongoing CTC element for PG&E to be charged to any DA or DL customers for the year 2003. The one remaining dispute with respect to PG&E's 2003 URG costs has to do with the treatment of "New World" generation. We resolve this issue as discussed in Section VI.C below.

PG&E's 2004 ongoing CTC will either be established as a result of the ERRA proceeding (A.03-08-004), or in connection with PG&E's post-bankruptcy settlement rates (Advice 2465-E).

2. SCE

SCE submitted data on December 8, 2003 consisting of recorded URG expenses for 2001-2002 (including employee-related transition costs). SCE summarized the differences from using actual figures versus those adopted in D.02-04-016 relating to URG, as follows:

URG Revenue Requirements ($000s)

	Actual	Adopted Per D.02-04-016	Difference
2001	4,251,265	3,749,102	502,163
2002	3,188,852	3,749,102	(560,250)

Because some customers may be exempt from the DWR component of the "indifference rate" but not the CTC, SCE believes that a CTC must be developed for 2001 and 2002. SCE has not been collecting CTC, and believes that the Commission must decide on its CTC for 2001-2002 in this proceeding. SCE did not estimate employee-related CTC on the basis that the amounts involved were not material in the context of merely modeling such sensitivity impacts.

In its comments on the Draft Decision, SCE asks the Commission to adopt a market price benchmark for CTC for the 2001-2002 period so that it can calculate and collect the applicable CTC from applicable customers for those years. The market benchmark price of 4.3 cents/kWh adopted in D.02-11-022 applied only to 2003. No corresponding market benchmark price has previously been adopted for the 2001-2002 period.

The 2003 market benchmark price adopted in D.02-11-022 was derived from a report by the California Energy Commission (CEC). SCE was unable to locate a similar CEC report covering the 2001-2002 period. As an alternative, SCE suggests that a market price benchmark for those years be derived by computing the average cents/kWh price in the Independent System Operator (ISO) real time imbalance energy market for 2001 and 2002. In the absence of any alternative record data from which to derive a market price benchmark for 2001-2002, we shall adopt SCE's suggested approach. We thus direct that a market price benchmark for the 2001-2002 period be determined by computing the average cents/kWh price in the ISO real time imbalance energy market for each of those years. SCE shall include the calculations and documentation supporting its calculation of the 2001 and 2002 market price benchmark as part of its advice letter filing to implement tariff amendments to bill and collect CTC for 2001-2002.

In July 7, 2003, comments, SCE proposed to use recorded URG costs to calculate CTC for 2001-02, rather than using forecast sources as proposed by CMTA or PG&E. SCE does not believe that further evidentiary hearings are necessary to finalize the total DA cost responsibility for 2001-02 undercollections.

We hereby adopt SCE's proposal to use actual URG costs for the 2001-2002 period since they more accurately depict its costs compared with the forecasts that were adopted in D.02-04-016. We also adopt SCE's recommendation that undercollections for CTC-only customers be tracked separately, by and for each utility. The Commission adopted a 2003 URG revenue requirement for SCE in D.04-01-048 (in SCE's ERRA A.03-04-022). SCE's 2003 URG revenue requirement incorporated the above-market portion of costs which are eligible for ongoing CTC treatment as provided in D.02-11-022. In that decision, we authorized SCE to track its CTC-eligible costs in its DA Cost Recovery Surcharge Tracking Account. Thus, no further disposition is required in this decision of SCE's CTC for 2003 and thereafter.

In its December 8, 2003 submittal, SCE provided actual recorded URG data for the first three months of 2003, and utilized forecast data for the remaining nine months of 2003. The use of the recorded data provides a more accurate data set for computing CRS obligations. We find the URG data submitted by SCE to be reasonable as a basis for computing the 2003 CRS obligations applicable to the SCE territory and shall accordingly adopt it.

3. SDG&E

In its December 8, 2003 submittal, SDG&E provided the applicable CTC-eligible URG data for 2001-2003 for use by DWR in computing the CRS obligations for the SDG&E service territory. We find the URG data submitted by SDG&E to be reasonable as a basis for computing the 2003 CRS obligations applicable to the SDG&E territory and shall accordingly adopt it.

SDG&E's ongoing CTC was initially set pursuant to D.99-05-051, and made effective when SDG&E ended its AB 1890 rate freeze on July 1, 1999. SDG&E's ongoing CTC was subsequently redesigned pursuant to D.00-10-0948, effective January 1, 2001. In D.02-12-064, the Commission adopted a settlement whereby SDG&E's CTC component would continue in effect until such time as the AB 265 balancing account has been reduced to zero and then at that time it would be revisited and adjusted in accordance with remaining tail costs. SDG&E took the position during the DA CRS cap re-look phase that because it has no sunk costs left to recover pursuant to AB 1890, and because its "Incremental Cost Incentive Price" mechanism associated with the San Onofre Nuclear Generating Station was due to end after 2003, that no other utility retained generation costs remain to be addressed in the CTC component. Thus, SDG&E did not offer any testimony on CTC cost data in the DA CRS re-look phase.

SDG&E argues that no further review of its CTC should be undertaken at this time. SDG&E asks that the Commission not consider changing its CTC at least until the AB 265 balancing account has been reduced to zero, as specified in D.02-12-064. At that time, SDG&E believes the CTC could be revisited and adjusted if necessary. SDG&E provided its CTC data to Navigant prior to the December 16, 2003 Workshop.

CMTA argues that SDG&E's CTC was not consistent with the total portfolio approach adopted in D.02-11-022 in that SDG&E excluded URG resources below benchmark costs.

Navigant points out that SDG&E's CTC element does not impact the 2001-2002 historical undercollection. For those years, the CTC component was accurately reflected as zero. However, for the 2003-2004 undercollections, SDG&E's CTC does play a role in the undercollection calculation, and its CTC should not be reflected as zero. Navigant concurs that SDG&E's CTC should be accounted for in Navigant's anticipated updates. Navigant recommends continuing SDG&E's established CTC rather than deriving a different figure from the market benchmark.

Due to the unique circumstance surrounding SDG&E's AB 265 undercollection, we agree that it is appropriate to use SDG&E's currently adopted CTC for its 2001-2003 DA CRS modeling. Moreover, the DA customers in SDG&E's service territory may soon pay off their CRS obligations, making SDG&E's CTC less of an issue as it relates to the CRS indifference calculation.

C. Treatment of "New World" Generation in the CRS Calculation

1. Positions of Parties

In calculating "total portfolio" indifference costs beginning in 2003, a point of dispute has arisen concerning how to reflect new long-term URG resources procured by the IOUs, referred to as "New World" URG. The treatment of "New World" resources in the calculation of CRS obligations must be addressed before CRS obligations can be determined for 2003 or any subsequent year. "New World" URG specifically refers to contracts and generation resources acquired by the IOUs since January 1, 2003, when they resumed responsibilities, previously held by DWR, for power procurement. In calculating the "total portfolio" indifference amount for the year 2003, DWR did not use the actual price of "New World" URG resources, but instead substituted the CTC benchmark of 4.3 cents/kWh, as adopted in D.03-07-030, for pricing those resources.

PG&E objects to DWR's exclusion of "New World" URG costs from the CRS calculation arguing that it fails to produce bundled customer indifference, as required by D.02-11-022. PG&E argues that depending on whether the adopted CTC benchmark is above or below the IOU's average cost of New World URG, the benchmark over or underestimates the amount that nonbundled customers must bear to maintain bundled customer indifference. PG&E argues that the costs of new generation procured by utilities should be included in the CRS calculation for all DA customers at prices paid by the utilities.

CLECA disagrees with PG&E, arguing that the costs of New World resources should not be included at all in the indifference calculation. TURN proposes excluding New World URG volumes and costs in the indifference calculations.

TURN argues that while DWR's treatment of New World generation is correct as to the CTC component standing alone, TURN is not convinced that the overall indifference calculation would remain neutral with respect to New World resources.

TURN suggests that one reasonable approach might be to exclude both the New World resources AND the portion of bundled load that they serve from the indifference calculation. By removing both the costs of these resources and the related volumes from BOTH the numerator and the denominator of the calculation, it may be possible to determine an indifference cost that is completely independent of New World resources.

For illustrative purposes, DWR calculated the effects on the CRS obligation under varying assumptions proposed by parties with respect to how New World URG is treated. The 2003 results under each of the different assumptions are summarized below:

	2003 Cost Responsibility Undercollection ($000s)		
Assumption	PG&E	SCE	SDG&E
No New World URG Adjustment	256,675	544,815	42,600
New World URG set at CTC Benchmark	251,747	540,837	40,818
Exclude New World URG Volumes & Cost	253,080	551,070	43,938
Exclude New World URG Costs Only	248,912	523,191	33,452

2. Discussion

We conclude that DWR/Navigant's proposed treatment of New World resources offers the most defensible approach to computing the DA cost responsibility obligation. DWR included "New World" resource volumes in its CRS calculation, but applied them only at the 4.3 cents/kWh market benchmark prices. DWR's approach is reasonable. Unlike DWR purchases, "New World" URG resources were not procured with the expectation that they would be required to serve DA load. Since 2001, and in the future, "New World" resources have been and will be added to meet forecasts of bundled customer load, but have not been and will not be used to serve DA customers. Thus, we conclude that the costs of these new generation resources in excess of the CTC benchmark should not be included in the CRS calculation.

We find no indications that "New World" generation resources are procured to serve DA customers in the event they return to bundled service in the future. DA load returning to bundled service must face a six-month waiting period, with generation priced at spot and then must commit to at least three years of service at bundled rates. Unless DA service is opened to new participants, the risks of serving potential returning load after a six-month hiatus seems manageable, and we have recognized it as such in our rules under which DA customers may switch to bundled service. DA customers should not be affected by costs that the IOU might commit to incur after such DA customers have left bundled service.

DWR appropriately includes the New World URG load volumes since these loads would be served notwithstanding the "New World" procurement. DWR's approach, however, relieves the DA customers of any additional CRS by effectively acknowledging that no incremental costs of these new resources are attributable to DA load.

Inclusion of New World URG costs is not required to achieve bundled customer indifference within the meaning of D.02-11-022. As adopted in D.02-11-022, the objective of the indifference calculation is to avoid cost shifting as prescribed by AB 117, by holding DA customers responsible for costs of power. Yet, since the New World resources were procured only after DA customers had already migrated, the costs of such resources were not procured on their behalf. Thus, since none of the "New World" resources were procured for the purpose of serving existing customers, there are no costs associated with those resources to be shifted, within the meaning of AB 117.

Our adopted treatment of New World Resources thus assumes that CRS is applied only to *existing* DA customers' load. PG&E, however, points out that the question of how it plans for load that ultimately represents *new* DA customers or community choice aggregation load, and the extent to which PG&E may acquire resources to serve that load is the subject of R.04-04-003. We make no judgment in this order concerning the extent to which it may appropriate in future CRS calculations for the cost of New World resources to be applied to any *new* DA customers and community choice aggregation load.

PG&E argues that if DA customers had not been allowed to leave bundled service they would be sharing in the actual costs of PG&E's portfolio, including the actual costs associated with PG&E's "New World" purchases. (PG&E Comments, p. 5.) PG&E makes this argument in spite of the fact that these resources would have been added ***after*** DA customers left bundled service in 2001. PG&E thus procured "New World" resources with advance knowledge concerning the levels of DA that had already departed. "New World" resources were only procured to serve bundled load, excluding DA. DA customers have contracted for other resources to serve themselves.

The timing with respect to procurement of "New World" resources is distinct from procurement under DWR contracts that were entered into during early 2001 without recognition of DA load that subsequently departed. It was with the intent of capturing such unforeseen migrations that we devised the DA-in methodology. The DA-in methodology is not intended to load in all new URG resources in perpetuity as additional DA cost responsibility.

Since DA has been suspended, the utilities know the amount of DA load on their systems, apart from limited DA load changes that are permitted pursuant to D.04-07-025 on DA load growth. The amount of DA load is not expected to change dramatically unless new DA were to be permitted. We conclude that current DA customers should not be required to pay above-market costs for new additional generation resources added by the utilities to serve bundled load after these customers have left bundled utility service and chosen an alternative supplier.

The issue of ongoing CRS calculations in the face of utilities returning to the procurement business was not addressed by the Commission until the recent Mountainview decision (D.03-12-059), which adopted a recommendation by TURN that new resources not be included in the CRS calculation for existing DA-eligible customers.[15]

> "[W]e adopt TURN's proposal that all customers of Edison that are currently ineligible for direct access be obligated to pay for stranded costs for the first 10 years of Mountainview's life." (D.03-12-059, mimeo., Finding of Fact (FOF) 32.)

This language indicates that existing DA and DL customers have no responsibility for "New World" generation because they left bundled service in 2001 or earlier.

D.04-01-050 (in R.01-10-024) develops rules for long-term procurement plans for the utilities to serve bundled load, not all load. In this decision, we concluded that the Commission has authority to impose reserve requirements on non-utility load serving entities (LSEs) and that each LSE in the utilities' service areas should have an obligation to acquire sufficient resources for their customers (sic) load."[16] Since LSEs, including the utilities, are to provide reserves to meet the needs of their supply customers, charging DA load for resources intended to serve bundled customers would lead to double counting for such resources. We shall, therefore, adopt DWR's recommended approach for the New World URG.

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[15] D.03-12-059, at pp. 63, 68.

[16] Conclusions of Law 2 and 4.

VII. Disposition of Miscellaneous Issues Relating to CRS Indifference Methodology

A. Disposition of the $1 Billion Revenue Reduction for 2003

In D.03-09-018, the Commission implemented a reduction of approximately $1 billion in DWR's 2003 revenue requirement.[17] In the case of bundled customers, D.03-09-018 directed that 100% of the $1 billion reduction be passed through to them as a one-time billing credit. In the case of DA and DL customers, D.03-09-018 deferred to R.02-01-011 the issue of "the specific portion of the reduction that may be attributable to DA or DL cost responsibility…[and] to ensure that no costs attributable to DA and DL customers are shifted to bundled customers, in accordance with the principles outlined in D.02-03-055." (D.03-09-018 at 2.) Parties in this proceeding raised a dispute concerning the manner and extent to which Customer Generation DL customers should receive a share of the $1 billion refund.

Navigant has taken into account the effects of the $1 billion revenue reduction by lowering the DA cost responsibility accrual amounts applied monthly through the 2003 and 2004 periods. DA customers paying the power charge thus realize an appropriate share of the $1 billion reduction through lower accruals to the CRS undercollection during 2003 and 2004.

1. Positions of Parties

EPUC proposed that a one-time billing credit be passed through to CGDL customers related to their share of the $1 billion reduction in the DWR revenue requirement for 2003. EPUC argues that CG DL customers are in a

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[17] D.03-09-018, OP 1.

different situation from DA customers. Because CG DL customers are not currently assessed a DWR power charge, they do not contribute toward the undercollection accumulating pursuant to the 2.7 cents DA CRS cap. As a result, EPUC argues that a reduction in that undercollection for the effects of the $1 billion DWR reduction may benefit DA customers, but will not allocate any share of the $1 billion reduction to CG DL customers.

PG&E agrees that D.03-09-018 requires that departing load paying the bond charge receive a credit for a share of the 2003 DWR power charge revenue requirement reduction that was passed through to bundled customers via a one time bill credit. PG&E proposes that these departing load customers receive their credits via a reduction in the bond charge amount that they are obligated to pay, but have not yet paid. SDG&E argues that EPUC/KCC's one-time credit proposal is unworkable, and it is premature to determine an appropriate undercollection adjustment for DL customers.

2. Discussion

We decline to grant an immediate one-time billing credit to CG DL customers for a share of the $1 billion reduction, as proposed by EPUC. Since 100% of the $1 billion reduction has already been flowed through to bundled customers, no additional cash reserves currently remain from which to credit CG DL bills as an immediate one-time pass-through. Providing such an immediate one-time reduction to departing load customers would require an offsetting increase in the obligation of bundled customers. Bundled customers are already bearing a burden for DA/DL CRS undercollections generally, and we will not burden them further.

Moreover, granting CG DL customers an immediate billing credit would be contrary to our intentions expressed in D.03-09-018. As we stated in

D.03-09-018: "to the extent that any of the reductions in the 2003 DWR revenue requirement are attributable to DA and DL customer obligations …, [the Commission] will reduce the CRS undercollection to be paid off in future years." (*Id.*, at 16-17). We thus contemplated, not a one-time billing credit, as requested by EPUC/KCC, but rather, a *reduction* over time to the extent the DWR funds are attributable to DA and DL customers.

Although CG DL customers are not currently contributing to the CRS undercollection for the power charge, they are responsible for a DWR Bond Charge and, currently do have an undercollection for their bond responsibility which was effective April 3, 2003. The Decision found that: "Allocating the reduction in DWR's 2003 revenue requirement to all customers that pay the bond charge will result in the largest number of customers benefiting from the reduction." (*Id.*, Finding of Fact 8). We conclude, therefore, that the appropriate way to assign the applicable share of the $1 billion refund to CG DL customers is through a prospective reduction in the undercollection attributable to their DWR Bond Charge obligations over future periods. Using this approach, the departing load customers will receive their offset to the extent that they actually pay DWR bond charges. We shall accordingly direct that CGDL accruals for DWR bond charge obligations for 2003 and 2004 be reduced by the applicable amounts necessary to reflect the effects of the $1 billion reduction for 2003. In connection with the true up for 2003 DWR charges, we shall direct that the appropriate calculations be made to assign a proportionate share of the $1 billion reduction to the DWR Bond Charge and/or Power Charge being paid by DL customers. The specific reduction due to Customer Generation DL will be determined in proportion to the actual share of accrued obligation for DWR Bond and/or Power Charges that they were assessed for the year 2003.

B. Adoption of HPC Amounts

In its August 17, 2004, submission, DWR reported the results of cumulative accruals and collections associated with SCE's "Historic Procurement Charge" (HPC) applicable to DA customers in the SCE service territory. No party objected to these results. Accordingly, we find the HPC cost responsibility results reasonable, and hereby adopt them, as summarized in Appendix D.

DWR's financial model initially applied an interest rate to DA customers' HPC obligations that was not consistent with that adopted by the Commission pursuant to D.03-09-016 (FOF 8). In that decision, the Commission adopted an interest rate of 1% per month from September 1, 2001 to July 2003, the period SCE's Procurement Related Obligation Account (PROACT) was in effect, and with the interest rate adopted for the DA CRS undercollection applying after July 2003. DWR made a correction to its financial model to reflect the Commission-adopted interest rate for the HPC balance.

C. Effects of Differences in Load Shape Between Bundled and DA

Certain parties question the validity of assuming that the same mix of resources in comparing costs applicable to DA versus bundled customers in the context of computing the DA-in/DA-out scenarios.

In computing the DA-out scenario, DWR simply includes actual URG off-system sales and associated spot purchase costs. The DA-in scenario, by contrast, requires hypothetical assumptions concerning what additional costs would have been incurred to serve incremental bundled load if incremental migrations to DA had not occurred subsequent to July 1, 2001. DWR suggested alternative sets of assumptions concerning how the additional load associated with a DA-in scenario could have been met. Three possible alternative sources for serving incremental DA-in load are:

- Reducing off-system sales,
- Increasing spot power purchases and
- A mix of both reducing off-system sales and increasing spot power purchases.

In its calculations, DWR assumes that the increased DA-in load would be served by a combination of spot purchases and increased contract DWR and URG contract deliveries (less surplus sales). DWR assumes the same mix of spot purchases and surplus sales as for bundled customers' sales forecasts.

AReM questions the assumption that the weighted average price for spot and off-system sales for DA load is the same as for bundled load. Because DA customers have a different load shape and load factor than do bundled customers, AReM argues that such differences should be taken into account when pricing spot purchases and off system sales, and that by not accounting for such distinctions, DWR overstates DA customers' stranded costs. AReM recommends that a modeling methodology be developed that better reflects the hourly prices of power bought and sold.

TURN likewise expresses concern that DWR used only average monthly recorded spot purchase and sales prices in its "DA-In" hypothetical case, rather than a breakdown of prices by peak and off-peak periods. However, TURN believes that bundled customers, not DA customers, are disadvantaged by this approach. If DA customers have flatter load profiles, then the migration of load to DA would result in a greater proportionate level of off-system sales at a loss during off-peak periods, driving the indifference amount *up* rather than down.

Navigant reviewed its model to determine whether differences in load shape and load factor make a material difference in the CRS obligations. Based on a cursory review, Navigant stated that pricing the change in load at the hourly market clearing price using the DA load shape would increase the CRS slightly compared to DWR's proposed approach of pricing at the average bundled spot and surplus sales price. Navigant believes that including different load shapes and load factors for DA customers in the modeling process may be cumbersome.[18]

Because the effects on the CRS calculation are not material, we shall accept the assumptions made by Navigant for the 2001-2003 period, with respect to the mix of spot purchases and off-system sales based upon bundled load. We reserve the option of considering different assumptions for subsequent years, however, in calculating the DA-in scenario depending on the materiality of the assumptions.

D. Assumed Prices for Off-System Sales an Natural Gas Purchases

AreM objects to the assumptions applied by DWR/Navigant in computing 2003 model runs relating to off-system sales and natural gas prices.

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[18] Because DWR was procuring net short requirements for customers in the IOUs' service territories during 2001-02, DWR had access to spot purchase price and volume data to the extent used to serve bundled load. Since DWR no longer procures short-term energy for customers in the IOU service territories after January 1, 2003, DWR no longer has access to the prices or volumes for this source of energy for periods after 2002.

The combined effects of AReM's adjustments to the off-system sales and the natural gas prices on the CRS accrual amounts for 2003 are as follows:

	DWR Model	**AReM Proposal**
PG&E	$27.81	$22.48
SCE	$42.51	$33.36
SDG&E	$17.23	$15.35

AReM objects to DWR's assuming an off-system sales price of only 75% of the market-clearing price. AReM argues that the model should apply an off-system sales price of 100% of the market-clearing price in order to be consistent with the assumptions adopted by the Commission in D.03-07-030. AReM calculated the change in assumed accrual rate for 2003 by valuing off-system sales at 100% versus 75% of the market-clearing price (in $/MWh), as set forth below:

	75% of Market Price	100% of Market Price
PG&E	$27.81	$24.89
SCE	$42.51	$36.56
SDG&E	$17.23	$16.95

DWR discounted off-system sales to 75% to reflect its experience in the market in 2001 and 2002, and preliminary trading results from the IOUs in 2003. DWR claims that its forecasts of off-system sales prices reflect its experience concerning actual trading results, and that the resulting forecasts form a reasonable basis for use in computing the cost responsibility applicable to 2003. We shall utilize DWR's off-system sales assumptions for purposes of deriving the 2003 cost responsibility obligation. To the extent actual results prove to be different from the forecast assumptions used in DWR's calculations, the appropriate adjustments to the cost responsibility obligation will be made as part of the periodic true up process. Moreover, by our actions in this decision, we make no prejudgment concerning what market price assumptions may be appropriate for off-system sales in forecasting CRS requirements for subsequent years.

AReM also takes exception to the natural gas prices assumed by DWR in its calculation of the 2003 DA CRS accrual rates, and proposes different gas price assumptions. In its model for 2003, the gas prices that DWR used are somewhat low relative to the gas price forecast assumed in D.03-07-030, not too far from the actual index values reported in *Gas Daily*. AReM applied the ratio of the low and base case scenario gas price assumptions from the CRS cap re-look proceeding to modify the CRS accrual amounts produced in the December 2003 DWR model run. The table below shows the effects of AReM's proposed adjustment to the accrual rates for each utility as a result. AReM incorporated the HPC for SCE in the accrual rate as well as DWR Bond Charges for all three IOUs.

Effects of AReM Gas Price Adjustments

	DWR Model	**AReM Proposal**
PG&E	$27.81	$25.06
SCE	$42.51	$38.46
SDG&E	$17.23	$15.59

DWR indicates that it has utilized the same natural gas price forecast in its 2003 CRS accrual projections as it has used in its 2003 DWR revenue requirement. Accordingly, we conclude that DWR has properly complied with the Commission-adopted methodology in D.02-11-022 for computing the indifference calculation which was to be premised on consistency between the DWR revenue requirement and the DA/DL cost responsibility indifference calculations. Thus, we decline to adopt disparate resource assumptions, as proposed by AReM. Through the process for the periodic true up of prior year CRS results, as we adopt herein, any variances between the adopted forecast amounts and actual results will be reconciled over time.

E. Treatment of DA Load Variations Over Time

In preparing its calculations of indifference cost, DWR interpreted D.02-11-022 as requiring that a fixed volume of DA load migration be used, based on the difference between DA load volumes at July 1, 2001 and September 20, 2001. DWR assumes, however, that the Commission intended to measure the change in qualifying customer volumes on a going forward basis.

DWR thus presented four options for addressing how variations in DA load over time could be measured to assure that bundled customers will remain financially indifferent, as summarized below:

1. DA load is calculated as of July 1, 2001 and September 20, 2001 and the difference in loads becomes the fixed volume of load migration, used on an ongoing basis in the indifference calculations.

2. DA load of customers as of July 1, 2001 and September 20, 2001 is tracked monthly, so that the indifference shortfall in a particular period is based on the *current* load of each group.

3. The July 1, 2001 and the September 20, 2001 DA load percentages are applied to current bundled volumes to produce the migrating load used to calculate the indifference shortfall.

4. The July 1, 2001 DA load percentages and the current DA load percentages are applied to the current bundled volumes to produce the migrating load used to calculate the indifference shortfall

The second and fourth options were supported by parties in their comments. DWR supports the fourth option, only because it isn't sure whether all three IOUs can readily provide July 1, 2001 DA customer's current load level, as would be required under the second possibility.

SDG&E supports DWR's recommendation to use the fourth option for capturing DA load migration, which uses the actual percentage of DA load in the period for which the shortfall is being calculated <u>and</u> is adjusted for exempt DA load. This approach will capture actual DA load growth or attrition and will therefore provide a consistent match between DA non-exempt loads to costs between periods. SDG&E supports this methodology for purposes of calculating the indifference shortfall, and it correctly applies costs to the DA CRS to non-exempt DA load. SDG&E notes that since DWR only bought for non-exempt DA load in its power contact purchases, only non-exempt DA load should be accounted for in the determination of any load growth or attrition.

In its January 30, 2004 comments, TURN supports the fourth method. Particularly under a "backcast" approach to the determination of the DA CRS liability, TURN argues, changes in the percentage of load served by DA over time MUST be captured in the indifference analysis. DWR proposes to do this by calculating the difference between the percentage of total load served by DA on July 1, 2001 and the DA percentage of current load (presumably on a monthly historical basis).

In order to maintain bundled customer indifference, the calculation should capture all ongoing variations in DA load. Accordingly, DWR's first described option would be inappropriate. We shall adopt the fourth option as the appropriate method by which to measure changes in DA load volumes in performing the indifference calculations. Under this approach, the July 1, 2001 DA load percentages and the current DA load percentages are applied to the current bundled volumes to produce the migrating load used to calculate the indifference shortfall. The percentage of load served by DA is unlikely to remain exactly the same over time. As the percentage of DA load varies over time, the total cost responsibility of DA customers should likewise track such variations. If the DA obligation were calculated on a fixed volume of DA load, future reversions of DA customers back to bundled service would drive up the DA obligation on a per unit basis, incenting additional migration back to bundled service. Moreover, use of the current DA load percentage in the indifference analysis would tend to correct automatically for any growth (or reduction) in DA load over time.

F. CRS Determination Based on Annual True-Up Versus Prospectively-Only

Several parties support DWR's recommended true-up approach for the final determination of DA / DL customers' responsibility for the indifference amounts. No party opposed this recommendation. PG&E and TURN withdraw their earlier objections, with caveats that the approach DWR uses may need to be changed in the future if circumstances change.

PG&E recommends that on an ongoing basis that the indifference amount be calculated on a forecast basis, for use in making entries into the appropriate ratemaking accounts. The indifference amount would then be trued up on an after the fact basis, using DWR's recommended true up approach. PG&E recommends that for 2001-2002, the DWR after-the-fact true-up calculation be used to set the indifference amounts.

For 2003, PG&E recommends that estimated indifference amounts be calculated now, on a forecast basis. PG&E recommends that the true up be calculated for 2004, in conjunction with the proceeding allocating DWR's 2005 revenue requirement.[19]

Similarly, PG&E recommends that the estimated indifference amounts for 2004 be calculated now, on a forecast basis. The true up for the 2004 indifference amounts would occur in the DWR proceeding held in mid-2005. DWR did not calculate any shortfalls associated with categories of customers

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[19] A permanent allocation of DWR's power charge revenue requirement was adopted by D.04-12-014 in A.00-11-038 et al. Although a permanent allocation is adopted, a limited DWR proceeding will still be needed to true up the allocation of the 2003 DWR power charge revenue requirement. More generally, some sort of limited proceeding will be needed to set the power charge, as well as to true up the indifference amount, although a permanent allocation of DWR's power charge costs has been adopted.

who do not bear the full indifference amount. SCE notes that each utility should track these amounts separately. PG&E states there is no need to develop shortfall estimates for PG&E, other than the shortfalls associated with the indifference amount.

The benefit of truing up the CRS obligations annually is that doing so allows parties to eventually view the actual data that was used in the indifference calculations. This should help address their concerns about the confidential nature of the data that has prevented parties from viewing contemporary data incorporated into the model. A potential obstacle with this true up procedure is that the IOUs have not stated when they would agree that URG data for a particular period is no longer confidential.

PG&E has established shortfall accounts, and sub-accounts, designed to capture any over / under collections related to the DA / DL customers' CRS obligations. SDG&E asserts that all three utilities have followed the Commission's directive in D.03-07-030 to establish such accounts. To the extent that true-ups are conducted on a regular basis, such accounting will ensure that DA / DL obligations are current and balanced. Since the proposed true-ups will capture the balances of the shortfall accounts, it is not necessary to perform any customer rebilling. Since DA cost responsibility is capped at 2.7 cents / kWh, rebilling would result in no overall cost adjustment to the customer's bill, would offer no benefit, and could create unnecessary customer confusion.

TURN agrees that as long as the indifference obligation for DA customers for the past year is determined solely on the basis of recorded costs and recorded DA volumes, and any over- or undercollection of the DWR revenue requirement is assigned solely to bundled service customers in the following year, the DWR-proposed methodology should work effectively to determine the correct indifference amount, no more and no less. Further, the 'backcast" approach has the advantage of allowing interested parties greater access to the underlying data used in the indifference calculation, thereby addressing some of the concerns raised by parties such as AREM and CLECA.

TURN agrees with PG&E (pp. 3-4) that the backcast true-up calculations should be based on the trued-up DWR revenue requirement, including the effects of any inter-utility reallocations that result from the true-up process.

We shall adopt the approach proposed by DWR for determining the CRS indifference amount based on the use of annual true-ups. Thus, in the instant order, we adopt the CRS amounts for 2001-2002 based upon the true-up for this period utilizing the DWR revenue requirements and allocations adopted in A.00-11-038 *et al.* Since no true up has yet been completed for 2003, the results we adopt in this order for 2003 reflect the prospective forecasts of DWR revenue requirements. After the true-up of the 2003 DWR revenue requirement has been completed, we shall promptly finalize the CRS true-up calculations for 2003. Concurrently, with the 2003 CRS true up, we shall also proceed to implement the applicable calculations to determine the DA/DL cost responsibility for the year 2004, consistent with the adopted DWR revenue requirement for 2004.

VIII. Comments on Draft Decision

The draft decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on January 18, 2005, and reply comments were filed on January 24, 2005. We have reviewed parties' comments and taken them into account, as warranted, in finalizing this decision.

In comments on the draft decision, DWR reports that various Enron entities have notified the ISO of a potential error in reading meters of Enron customers for the period July 2001, forward. During the time period December 2001 through December 2002, DWR is informed that Enron under-reported approximately 847,000 MWhr of customer load. DWR does not believe this under-reported load is reflected in direct access load estimates used to develop the cost responsibility requirements for 2001-2003 as set forth in the draft decision. DWR has no information regarding the IOU service territory or territories in which this Enron under-reported load was located. Assuming this load was not exempt from a cost responsibility surcharge, we shall incorporate any necessary adjustment to reflect this under-reported Enron load in proceedings addressing the true-up of cost responsibility requirements for 2003.

IX. Assignment of Proceeding

Geoffrey F. Brown is the Assigned Commissioner and Thomas Pulsifer is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. D.02-03-055 determined that as a condition of retaining the DA suspension date of September 21, 2001, a surcharge must be imposed on DA customers sufficient to make bundled customers economically indifferent between a DA suspension date of July 1, 2001 versus September 21, 2001.

2. Cost responsibility obligations are applicable to CGDL and MDL in accordance with the relevant provisions of D.03-04-030 (for CGDL) and D.03-07-028 (for MDL) and successor decisions, respectively.

3. The results of the computer runs performed by Navigant as set forth in Appendix A of this order, based on the scenario that prices "New World" URG at the CTC benchmark, provide a reasonable measure of the cost responsibility

obligation applicable to DA and DL customers for the period 2001-2002 and for 2003, in accordance with Commission orders applicable to each category of load.

4. The calculations of DA cost responsibility for DWR Bond Charges, as set forth in Appendix C, appropriately reflect the accruals, collections, and obligations of DA and DL customers through the year 2003. For Customer Generation DL, the obligation for the DWR Bond Charge began to accrue effective April 3, 2003.

5. The DWR Bond Charge undercollection shown in Appendix C on an aggregate basis can be allocated as between DA and DL categories based on the relative percentage of load assigned to each category, as follows:

Departing Load Responsible for DWR Bond Charge
As a Percentage of Total Eligible Volumes

	PG&E	SCE	SDG&E
2001	0%	0%	0%
2002	1.30%	0.43%	2.01%
2003	7.38%	6.19%	11.95%

6. The Navigant model does not separately distinguish DL volumes as between Customer Generation or Municipal load, nor subcategories within these two major DL categories.

7. With respect to MDL, the applicable volumes for DWR Bond Charge responsibility is yet to be quantified through the billing and collection phase of this proceeding.

8. PG&E included some DL volumes associated with the CRS power charge obligation for 2003 in its service territory (albeit at de minimis levels), while SCE and SDG&E included zero DL volumes associated with the CRS power charge obligation for 2003 in their respective service territories.

9. The calculations of DA cost responsibility for the "Historic Procurement Charge" in the SCE service territory, as set forth in Appendix D, appropriately reflect the accruals, collections, and obligations of DA customers through the year 2003.

10. The calculations of the CRS power charge, as calculated by Navigant, do not include volumes of load for DA or DL customers that are exempt from the DWR power charge.

11. The calculation of the CRS power charge obligation for the 2001-2002 period is computed based upon DWR costs, as adopted in the DWR true up for 2001-2002, as reflected in Appendix B of this decision.

12. The calculation of the CRS power charge obligation for the 2003 period is computed based upon DWR costs as adopted prospectively for the 2003 period. A true up of DWR costs for the 2003 period has not yet been completed.

13. The cost responsibility for power charges DA load set forth in Appendix A is based upon a calculation that compares the costs of serving incremental DA load levels at July 1 versus September 21, 2001 under the "total portfolio" approach adopted in D.02-11-022.

14. Based on the calculations performed by the Navigant, the resulting undercollection for DA cost responsibility power charge obligation for the 2001-2002 period is for PG&E, $234,870,000; for SCE, $354,751,000, and for SDG&E, $42,690,000.

15. Based on the calculations performed by the Navigant, the resulting undercollection for DA cost responsibility power charge obligation for the 2003 period (corrected for certain computational errors) is for PG&E, $251,747,000; for SCE, $540,837,000; and for SDG&E, $40,818,000.

16. UR, data provided in December 2003 by the IOUs for the 2001-2003 period are reasonable for use by DWR/Navigant in producing the calculations of CRS Power Charges based upon the total portfolio indifference methodology adopted in D.02-11-022.

17. For purposes of calculating CTC for 2003, the market proxy of 4.3 cents/kWh is appropriate to use pursuant to D.02-11-022. For purposes of calculating CTC for 2001 and 2002, it is reasonable to use the same approach as that adopted for 2003, with market price benchmark derived by computing the average cents/kWh price in the Independent System Operator (ISO) real time imbalance energy market for 2001 and 2002, respectively.

18. For purposes of calculating CTC for 2004 and later years, the market proxy should be updated as determined in the relevant ERRA proceeding.

19. PG&E previously collected CTC revenues from DA customers during 2001-2002 through the one-cent electric procurement surcharge (EPS) implemented in D.01-01-018 to assist in paying for power during the energy crisis in 2000-2001.

20. DA customers' obligation for CTC relating to PG&E's one-cent EPS was resolved in D.04-02-062 in which the Commission adopted a Rate Design Settlement implementing provisions of D.03-12-035 in PG&E's bankruptcy proceeding.

21. PG&E does not propose to recalculate DA or DL customers' bills for 2003, regardless of the combination of responsibility that the customer has for the DWR bond charge, ongoing CTC, or the DWR power charge.

22. SCE's calculation of CTC for 2001-2002 based on recorded URG costs is reasonable.

23. SCE's URG requirements as adopted in D.04-01-048 form the basis for deriving SCE's CTC for 2003.

24. In D.02-12-064, the Commission adopted a settlement whereby SDG&E's CTC component would continue in effect until such time as the AB 265 balancing account has been reduced to zero and then at that time it would be revisited and adjusted in accordance with remaining tail costs.

25. New World" resources were not added by utilities with the expectation that they would have to serve existing DA or DL load.

26. Since "New World" resources were not procured for the purpose of serving existing DA and DL customers, there are no costs associated with those resources to be shifted from DA to bundled customers, within the meaning of AB 117.

27. Exclusion of "New World" resources from the cost responsibility power charge for existing DA and DL customers maintains bundled customer indifference and avoids cost shifting within the meaning of AB 117.

28. No judgment is made in this decision concerning the extent to which it may be appropriate in future CRS calculations for the cost of New World URG to be applied to any <u>new</u> DA customers and community choice aggregation load.

29. A benefit of truing up the CRS obligations annually is that doing so allows parties to eventually view the actual data that was used in the indifference calculations.

30. To the extent that Navigant's forecast assumptions, including those for the market-clearing price for off-system sales and natural gas prices, differ from actual results, the appropriate reconciliation to the CRS obligation will be made as part of the periodic true up process.

Conclusions of Law

1. The cost responsibility obligations applicable to qualifying DA/DL customers, as set forth in Appendix A have been determined on a basis consistent with the requirements of D.02-11-022. The figures in Appendix A, based upon the calculations submitted by DWR/Navigant on June 8, 2004, with "New World" URG priced at the CTC benchmark, should be adopted as the amount of DA cost responsibility obligations for the Power Charge for the periods 2001-2003, as shown.

2. The DA cost responsibility obligations for the DWR Bond Charge, as set forth in Appendix C of this order should be further reviewed by parties prior to final adoption.

3. The accrued DA obligations and undercollections applicable to the "Historic Procurement Charge" as set forth in Appendix D are reasonable and should be adopted.

4. The IOUs should make the appropriate accounting entries to reflect the obligations and associated undercollections due from DA/DL customers for the periods 2001-2003 consistent with the amounts adopted in Appendix A of this order.

5. No immediate changes in IOU tariffs are required as a result of this order since the CRS is currently capped at the rate of 2.7 cents/kWh, with any actual cost responsibility in excess of the cap to be accrued for accounting purposes as an undercollection to be remitted at a later date.

6. Due to the unique circumstance surrounding SDG&E's AB 265 undercollection, it is appropriate to use SDG&E's currently adopted CTC for its 2001-2003 DA CRS modeling.

7. Pursuant to D.04-02-062, past payments by DA customers during 2001 and 2002 of the one-cent Electric Procurement Surcharge and residual CTC were deemed to be the full and final obligation of these customers to PG&E's headroom.

8. No separate CTC element needs to be identified for PG&E with respect to the 2001-2003 period.

9. SCE should be authorized to implement tariffs to bill and collect CTC for the periods 2001-2003 from eligible DA/DL customers that are not otherwise obligated to pay the DWR power charge.

10. SCE should utilize a market price benchmark for the 2001-2002 period using the same methodology as adopted in D.02-11-022 for 2003 by computing the average cents/kWh price in the ISO real time imbalance energy market for each of those years.

11. DWR's treatment of "New World" URG for 2003, pricing based upon the CTC proxy of 4.3 cents/kWh provides a reasonable approach in computing cost responsibility and should be adopted.

12. The appropriate manner by which to pass through the applicable share to DA and DL customers of the $1 billion reduction in the 2003 DWR revenue requirement is through a prospective reduction in the accrual amounts applicable to the Power Charge and/or Bond Charge.

13. DL customers should not be granted an immediate one-time credit for their share of the $1 billion reduction in the 2003 DWR revenue requirement, but should realize the reduction through a prospective reduction in the applicable DWR Bond Charge otherwise applicable.

14. Although Navigant's assumptions are reasonable for the 2001-2003 period in calculating the DA-in scenario based on the mix of spot purchases and off-

system sales for bundled load, separate assumptions should be considered for subsequent periods in calculating the DA-in scenario.

15. In capturing the effects of DA load variations over time, the July 1, 2001 DA load percentages and the then-current DA load percentages should be applied to the then-current bundled volumes to produce the migrating load used to calculate the indifference shortfall.

16. A true up of the 2003 CRS power charge indifference amount still needs to be determined, as well as prospective 2004 CRS amounts. The adopted 4.3 cents/kWh market price benchmark needs to be trued up to reflect actual natural gas prices as part of the overall true up of 2003 CRS requirements.

O R D E R

IT IS ORDERED that:

1. The calculations of cost responsibility obligations for 2001-2003 applicable to eligible Direct Access (DA) and Direct Load (DL) customers within the service territories of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), respectively as set forth in Appendix A of this order, with "New World" generation priced at the CTC benchmark are hereby adopted.

2. The following amounts are hereby adopted as the cumulative undercollected cost responsibility obligation for DA load as of December 31, 2002 and 2003, respectively, in accordance with the amounts set forth in Appendix A.

	($000s) Undercollection as of:	
Investor-Owned Utility Territory	12/31/02	12/31/03
(a) For PG&E	$234,870	$251,747

(b) For SCE	$354,751	$540,837
(c) For SDG&E	$ 42,696	$ 40,818

3. The utility retained generation (URG) costs, as submitted by the investor-owned utilities (IOUs) and as reflected in the calculations of the Cost Responsibility for Power Charges, as set forth in Appendix A are hereby adopted.

4. SCE is authorized to file an advice letter to implement collection of CTC accrued for the years 2001-2003, from those eligible DA/DL customers that are not otherwise obligated to pay the DWR power charge. SCE shall include the calculations and documentation supporting its calculation of the 2001 and 2002 market price benchmark as adopted in this decision as part of its advice letter filing to implement tariff amendments to bill and collect CTC for 2001-2002.

5. Each of the IOUs is hereby authorized and directed to make the appropriate accounting entries to reflect the cost responsibility obligations and undercollections payable by eligible DA and DL customers.

6. The motion of PG&E dated December 8, 2003, for authority to file and maintain commercially sensitive, proprietary information under seal is hereby granted.

7. The URG data submitted to DWR by the IOUs in December 2003 form a reasonable basis for calculating CTC to the extent that it is required for those DA customers that are exempt from paying the DWR power charge.

8. Upon Commission determination of the DWR revenue requirement true up for 2003, the assigned ALJ shall issue a ruling for finalizing the true up of the 2003 CRS obligations for power charges for determining the prospective 2004 CRS obligations for power charges.

9. The Customer Generation Departing Load (CGDL) accruals for DWR bond charge obligations for 2003 and 2004 shall be reduced by the applicable amounts necessary to reflect the effects of the $1 billion DWR revenue requirement reduction for 2003. The specific reduction due to CGDL will be determined in proportion to the actual share of accrued obligation for DWR Bond and/or Power Charges that they were assessed for the year 2003.

10. Further specific determination of the applicability of DWR Bond Charges and Power Charges as between Customer Generation and Muncipal Departing Load should be addressed in a subsequent order after further determination of the applicable volumes of MDL pursuant to the billing and collection phase of this proceeding.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDIX A
Explanation of Table

The attached table presents a summary of the calculation of the ongoing component of DA cost responsibility surcharge (CRS) obligation for the 2001-2003 utilizing the "total portfolio" indifference approach adopted in D.02-11-022. The accrual rate (on a $/MWh basis) in the first set of columns represents the rate at which the CRS obligation accrued during the specific time period.

The second set of columns shows the accrual amount, equal to the accrual rate multiplied by the eligible MWh volumes. The eligible DA volumes relate to load that migrated from bundled service to DA after February 1, 2001. The eligible volume for CGDL is defined in D.03-03-040.

The third set of columns shows the amount of collections, representing the funds that have been remitted by DA and DL customers. Because the CRS tariff was not implemented until January 1, 2003, there were no CRS remittances during 2001 and 2002.

The fourth set of columns shows the end-of period CRS balance owed by the DA/DL customers. The balance is the sum of the previous year's balance, interest, and the present year's accruals, less the present year's collections. DWR assumes that interest accrues on the prior year's balance plus one-half of any undercollection in the present year.

Table 1 consists of four sets of rows, with each set of rows consisting of data for three years (2001-2003). Each of the four sets of rows presents a different treatment of "New World" URG in the CRS calculations. Data for the years 2001 and 2002 remain the same irrespective of the different treatment of "New World" URG. Only year 2003 data results are changed under the different scenarios. For purposes of the 2003 CRS power charge obligations adopted in this decision, we have relied upon the DWR-proposed treatment of "New World" URG, as summarized in the second set of rows, entitled "New World URG Priced at CTC Benchmark (DWR Proposal)."

APPENDIX C

DA Cost Responsibility Obligations for DWR Bond Charges

DWR Bond Charge					
Year	**Accrual $000s**	**Collection $000s**	**Net Accrual $000s**	**Interest $000s**	**Balance $000s**
PG&E					
2001	**-**	**-**	**-**	**-**	**-**
2002	**4,061**	**-**	**4,061**	**12**	**4,073**
2003	**34,456**	**9,578**	**24,878**	**861**	**29,813**
SCE					
2001	**-**	**-**	**-**	**-**	**-**
2002	**5,719**	**-**	**5,719**	**17**	**5,736**
2003	**47,923**	**14**	**47,909**	**1,289**	**54,934**
SDG&E					
2001	**-**	**-**	**-**	**-**	**-**
2002	**683**	**-**	**683**	**2**	**685**
2003	**9,449**	**2,175**	**7,274**	**219**	**8,178**

(END OF APPENDIX C)

APPENDIX D

"Historic Procurement Charge"
Cost Responsibility for DA Load

The following amounts are hereby adopted reflecting the obligations of DA customers for the "Historic Procurement Charge" in the SCE Service Territory.

	Starting Balance	Collection	Accrual	Interest	Ending Balance
2001				$19,206	$492,206
2002	$492,206	$114,851	$377,355	$59,769	$437,124
2003	$437,124	$120,982	$316,142	$34,711	$350,853

(END OF APPENDIX D)

Pulsifer Agenda Dec. Appendixes A-B